

**SUMMARY OF
THE NREL WESTERN WIND AND SOLAR INTEGRATION STUDY
TECHNICAL REVIEW COMMITTEE CONFERENCE CALL**

November 5, 2009

The following is a summary of the presentations and the discussion at the Western Wind and Solar Integration Study (WWSIS) TRC conference call that took place on November 5, 2009. A list of conference call participants is provided in Appendix A. Two presentations can be accessed at <http://wind.nrel.gov/public/WWIS/TRC/11-5-09/>.

Executive Summary

The WWSIS is designed to look at the operational impacts of increasing the amounts of wind and solar in WestConnect, a transmission organization encompassing much of the Southwest. The WWSIS examines the impacts of 10% wind/1% solar both within the WestConnect footprint and outside WestConnect; 20% wind/3% solar within WestConnect with 10% wind/1% solar outside WestConnect; 20% wind/3% solar within WestConnect and outside of WestConnect; and 30% wind/5% solar within WestConnect with 20% wind/3% solar outside of WestConnect.

The TRC conference call focused on further quasi-steady state analysis results that examined intra-hour variability at the 1 minute level and presented the operational sensitivity analysis that General Electric (GE) had performed on issues raised by stakeholders at the July meeting. Presentations were given by Kara Clark and Nick Miller of GE on the quasi-steady state analysis and Gary Jordan of GE on the operational sensitivities presented by coal plant minimum operating levels, pumped storage hydro (PSH) operations, concentrating solar power (CSP) optimization, and the addition of plug-in hybrid electric (PHEV) vehicles. GE included additional slides on the sensitivity results for hydro power flexibility changes and unit expansion plans, but these were not discussed on the conference call due to time constraints.

Findings discussed on the call include the following:

- The intra-hour variation of renewable energy delivered to the system is small, but hourly regulation energy adjustments can be substantial.
- In the 30% renewable penetration case, regulation energy limits were reached and the system failed to balance for a short period.
- Ramp rates are the primary issue with regard to system balancing rather than the inherent variability caused by renewable energy.
- Increasing coal plant minimum operating levels causes more spilled energy and increases operating costs but has minimal effect on spot prices, variable costs, and emissions.
- Forcing PSH to run more increases WECC-wide operating costs and the overall result is that the economics do not seem to support additional PSH.
- Optimizing the use of CSP storage can lead to additional revenue for CSP owners.
- Adding PHEV load that charges at night increases operating costs, reduces the emissions reductions realized from adding renewables, and increases the value of renewable energy.

Introduction by Debbie Lew, National Renewable Energy Laboratory (NREL)

Since the stakeholder meeting in July, the WWSIS team had reviewed the results of the three scenarios (In-Area, Local Priority, and Mega Project) for the 10%, 20%, and 30% wind and 1%, 3%, and 5% solar cases and discussed “deep dives” and further scenarios that should be run. The consensus was for a scenario that consisted of 20% wind/3% solar both in WestConnect and throughout the Western Electric Coordinating Council (WECC) territory. The team had also discussed looking at higher solar penetration scenarios but decided it would not be feasible due to the lack of adequate solar data. They did decide there was a need to examine storage in more detail and different generator retirement and balance of generation scenarios. Stakeholders at the July meeting had also raised a number of issues, such as:

- minimum generation limits for coal-fired facilities and whether GE was properly respecting the limits;
- some of the results for PSH operation seemed counter-intuitive;
- whether CSP storage dispatch could be optimized;
- how PHEV penetration might affect the results; and
- whether base hydro units could be operated with more flexibility.

The WWSIS team had conducted some further analysis on the issues raised by stakeholders, the results of which were presented during the conference call.

Ms. Lew said the team planned to have the draft report out for comment by the end of December 2009, with a stakeholder meeting in January 2010. The plan is to have the final report issued in February 2010.

Kara Clark and Nick Miller, Quasi-Steady State

Quasi-steady state (QSS) analysis is an analytical approach that looks intra-hour operations. QSS is meant to provide validation and context for operational and statistical analyses by looking at time simulations of selected one-minute periods. It would be impossible to look at one-minute resolution for all 8,760 hours of the year, so selected periods of time that are of interest were chosen to analyze the dynamic response to ramp rates and how generation resources respond to changes. One of these windows was April 14-15, 2006, where the renewable energy generation exceeds the load.

The QSS algorithm is a Matlab-based tool that represents multiple areas with aggregate load, wind, and solar data. The boundary conditions are represented by hourly balance of portfolio generation dispatch and hourly import schedule responses to aggregate ramp (MW/min) and range (MW) limits. At the one-minute intervals, all aggregate load, wind, and solar profiles vary and the analysis looks at how regulating power provided by designated unit types responds to the changes. At the five-minute intervals, there is a simplified economic dispatch from participating unit types as identified in the MAPS analysis.

The analysis looked at a 24-hour period from April 14-15, 2006, for Arizona under the Local Priority scenario using the 10%, 20%, 20-20%, and 30% penetration cases. The 20-20% is the case where both WestConnect and WECC are at 20% wind/3% solar penetration levels. The one-minute wind data is from NREL; the one-minute solar data is interpolated from the 10-minute data; and the one-minute load data is interpolated from one-hour data (Slide 3).

The GE team presented a series of slides showing the simulation results for the 24 hours from 6:00 PM on April 14 to 6:00 PM on April 15, 2006. The input profile for this 24-hour period shows that around 3:00 AM Arizona reached 100% wind penetration (solar being done for the day) in the 30% case (about 7,600 MW) with load slightly dropping below renewable generation levels for a short time. This was followed by a steep roll-off of renewable generation (for all the cases) where wind output ramped down to about 1,500 MW and lower over 7 hours while load was ramping up, with an especially steep (about 4,000 MW in the 30% case) drop occurring between 9:30 AM and 11:00 AM (Slide 4). The system responses include the following:

- Even in the 10% case, conventional generation was required to ramp up quickly from 9-11 AM and the system shows a slight failure to balance minute-to-minute changes, for a short time (slides 5 and 6). The export schedule shows much smaller changes due mostly to the lack of maneuverability for the export schedules.
- Arizona is allocated 230 MW of regulation capacity, which is approximately 1% of peak load. A graph of regulation versus schedule changes in the 10% case (slide 7) shows big regulation actions are occurring around hourly changes. Load/wind/solar doesn't vary that much between hours but Arizona generation needs to make up for scheduled hourly changes, leading to the large hourly regulation adjustments.
- Total output in the 20% case shows similar patterns as in the 10% case but is shifted downwards as a whole, as conventional generation is displaced by wind and exports are affected (Slide 8). Also, departures from hourly schedules increase.
- In the 20%/20% case, exports are suppressed and Arizona's conventional generation output drops substantially, as the rest of WECC has equal penetrations of wind and solar. The 24-hour patterns are substantially different due to the changes in export and generation schedules (slide 9).
- There is significant variation in the 30% case, with net load reaching 0 MW and therefore, all non-wind and solar generation that is not de-committed must be exported (slide 10).
- A graph of regulation versus schedule changes for the 30% case shows large volatility in the hourly regulation changes as hourly scheduling commitments changes, even though within-hour renewables don't vary much more than in the other cases because of geographic diversity (slide 11). Arizona experiences a shortage of regulation, as regulation reaches its limits for several of the hours between 4:00 AM and 11:00 AM.
- A look at total generation by resource type outlines the following:
 - In the 10% case, gas turbines are unused (as in all following cases) and combined-cycle units reach minimum generation limits at about 3:00 AM and stay there until a fast ramp back up starts at 8:00 AM. Steam generation units drop close to minimum levels for a short time, but this is mainly due to down-ramping limitations (slide 12).
 - In the 20% case, combined-cycle units are gone by midnight, steam units are down significantly, and hydro is at a minimum throughout the night (slide 13).
 - In the 20%/20% case hydro is at minimum, combined-cycle units are almost non-existent, and steam units are getting de-committed during the night (slide 14). In this case, there are no exports as WECC-wide renewable generation is also up.
 - In the 30% case even steam units are mostly de-committed (slide 15).

The GE team presented some composite slides of the Area Control Errors (ACE) for all cases, which show that the system is having issues balancing during the worst ramping hours, which would probably result in a CPS (Control Performance Standard) violation (slide 16). A slide of all transmission area ACEs under the 30% scenario shows that control issues tend not to be coincident, and while Arizona violates its export schedule, the other areas do not (slide 17). This once again shows the importance of control area cooperation and that there is room for it, even at 30% wind/solar generation. A summation of all ACEs shows some pretty good swings and that dynamic resources can be shared (slide 18).

There was some discussion about regulation limits and whether MAPs has a constraint for down regulation. The GE team said MAPs has a minimum power constraint and is committing to meet load and spin up regulation, but not down. If MAPs incorporated down regulation might change the results. A participant asked about wind forecasting, and whether GE had looked at perfect versus imperfect forecasts. The GE team said they had examined both and that the forecast wasn't particularly inaccurate. The wind forecast had captured the wind drop-off but the system had been caught by the rapid changes in wind and export schedules. It seems that the rates of change early in the morning is the big issue when wind is ramping down dramatically. The system has a hard time keeping up with the high rates of change as load rises, wind falls off, and exports schedules alter. The GE team noted that there seems to be some kind of mis-coordination during this time of day that warrants further study. [Note that GE has since found a 1 hour time shift in the export schedule compared to generation dispatch that reduces the size and duration of the ACE especially at 30% penetration]

A participant noted the ACE Diversity Interchange (ADI) program would be netting generation movement across balancing areas, and that these results seemed to suggest this would not help the situation in Arizona very much and that perhaps what was needed was some sort of market. The GE team said they had no definitive answer to this. Collectively, the system has room to handle variability and one can't conclude one way or another from this picture whether or not variability would disappear with bilateral sharing of resources. It was noted that ADI was a move in the right direction but that taking ADI a step further to allow for sharing of dynamic resources (not just netting of ACE) would be more helpful. In the end, it is collapse of the generation stack that makes things interesting, not the incremental variability from wind and solar.

Gary Jordan, Operational Sensitivities Results

Several issues were discussed at the July stakeholder meeting that warranted further investigation as operational sensitivities. The GE team conducted some modeling around these sensitivities and presented a series of slides outlining the results for the following:

- Minimum operation of coal plants;
- Storage operation – PSH and CSP;
- PHEV;
- Base hydro flexibility; and
- Unit expansion plan.

Coal Unit Operation

The modeling assumptions set minimum coal unit operation at 40% of nameplate capacity; only minimum cycling of the coal plants occurred before the 30% case. The GE team obtained some actual minimum operating ranges from some coal plants in the region, which indicated that they could safely cycle lower in emergency situations (slide 3), although it would lead to component stress. The GE team then examined the original operating results for representative coal plants rated 100 MW, 350 MW, and 500 MW, and presented a series of graphs showing how often the plants cycled down to different levels over a year (slides 4 to 6). Very little cycling of coal plants occurs until the 30% case, when all of the plants are forced to cycle down to the minimum (40%) level multiple times during the year. A monthly look at the 500 MW plant showed most of the cycling occurred between January and April in the 30% case (slides 7 & 8).

The team then examined the sensitivity of the minimum coal plant setting by running additional scenarios with the minimum set at 50%, 60%, and 70%. This led to the following observations as compared to the base case of 40% coal plant minimum level:

- In the 30% wind penetration case, the system must spill more energy as the coal plant minimum level increases (slide 10).
- Minimal impact on unserved energy, system spot prices, and total WECC variable costs (slides 11-13).
- Operating costs increase, especially in the 30% case, indicating a penalty for not allowing coal plants to cycle down (slide 14). This effect increases as the minimum coal plant operating level increases, with operating cost impacts doubling between 50% and 60% and again between 60% and 70% in the 30% wind penetration case.
- Small impact on total emissions (slide 15).

Storage Operation

The GE team conducted additional modeling runs to examine sensitivities around changing electricity storage. This included forcing PSH to run more even if it appeared uneconomic; examining the operation of a new 100 MW PSH in Arizona under the assumption of perfect knowledge regarding spot prices; and maximizing CSP storage operations.

Discounting pumping costs resulted in PSH running more and led to the following observations from changing the PSH operations:

- WECC-wide operating costs increase (slides 18).
- With a perfect wind forecast, spot prices in AZN (Arizona and New Mexico zone) are depressed, overall price variability is reduced, and therefore, the economics of operating PSH shrink (slide 19).
- With an imperfect wind forecast, overall spot prices are also depressed but variability increases (slide 20). Therefore, the economics of operating PSH are better but operators would need to know when prices are going to be high and when they are going to be low.
- The incremental value of PSH in Arizona is far less than the cost of a new PSH unit (slide 21).

A participant asked if PSH was allowed to offer other services, such as regulation, in the model. The GE team said PSH was not allowed to offer other services in these model runs, and acknowledged that doing so might slightly alter the economics but probably not enough to change the overall result.

The GE team built a dispatch model with varying hours of CSP storage in an effort to determine the optimal dispatch for CSP plants. The model was optimized to maximize annual revenue on a 24-hour basis. CSP and spot price data was for the Local Priority, 30% penetration case. This led to the following observations:

- Optimal dispatch leads to stored energy being used during times of higher prices. A single site in Arizona experienced a daily revenue increase of 17.6% (slide 23).
- A series of graphs show the results for the regional CSP sites as they all gain value from optimizing storage (slides 24-30). Overall annual revenue increases range from 8% to 12%, with the highest revenue gains occurring over the winter months.

There was some discussion regarding the cost of adding storage to CSP plants and whether the dispatch profile that was modeled is actually achievable for CSP plants. A participant noted that putting storage into a CSP plant increases capital costs by about \$3,000/kW. The base capital cost of a CSP plant runs around \$4,500/kW and including storage increases that to \$7,500/kW. These figures were based on a trough-type CSP plant. CSP designs that include built-in storage (e.g., central receivers) do not experience such a large increase in capital costs. Also, it is uncertain whether a CSP can actually operate on this type of schedule, where the energy production is cycled on and off. The next step would be to include CSP operating limitations and see how much value can be gained, and whether it would justify the additional cost of including storage.

PHEV Operation

GE added load profiles to the model that simulated high PHEV penetration and then ran the simulation with and without renewables. They researched probable PHEV penetration levels from existing studies and based on these, assumed a 15% penetration of PHEVs for light duty vehicles and 3% penetration for heavy duty vehicles. This results in a maximum daily off-peak load increase of about 15% or 5,300 MW for the study area. Assuming the same PHEV penetration levels for the entire region resulted in a daily WECC-wide PHEV load of 35,248 MWh and an annual load of 12,865 GWh. The PHEVs were assumed to be charging at night, between 10:00 PM and 7:00 AM. The simulations lead to the following observations:

- Operating costs increase for all cases due to the additional load represented by the PHEV, ranging from \$1,100 million for the no-wind case to \$900 million for the 30% case (slide 34).
- Emissions reductions are reduced, especially with respect to SO_x emissions (slide 35). This is due to steam plants needing to run more to provide charging energy. The emissions results, however, are for electricity generation only, and do not include any emissions reductions that may arise from displacing fossil fuel use in transportation.

- The value of renewable energy to the WECC system increases, as the addition of PHEV load changes the cost profiles (slide 36). In this simulation, the value of wind increases by about \$2/MWh in the 10% renewables penetration case. This is due to the PHEV load causing an increase in spot prices that counteracts somewhat the decrease in spot prices that comes from adding wind to the system, therefore, the value of wind increases.

There was some discussion about whether simply adding load to the system was the right way to go about simulating PHEV. This approach is only half of the equation and looks at it from the utility's standpoint. None of the system benefits that can be derived by adding load at night are captured here. The emissions results as depicted in the presentation also does not show how dramatically SO_x emissions actually decrease from adding wind and displacing gas and coal generation. A participant suggested there may be a better way to present this information for the report.

The presentation also included several slides outlining the results of the GE team's investigations into granting base hydro operations greater flexibility and altering unit expansion plans. Due to time constraints, Mr. Jordan was unable to discuss these slides.

APPENDIX A
PARTICIPANTS
FOR THE WESTERN WIND AND SOLAR INTEGRATION STUDY
TECHNICAL REVIEW COMMITTEE CONFERENCE CALL
NOVEMBER 5, 2009

Conference Call Attendees

Acker, Tom, Northern Arizona University
Ahlstrom, Mark, Windlogics
Brinkman, Greg, NREL
Chadliev, Vladimir, NV Energy
Clark, Kara, GE
Clark, Charlton, DOE
Corbus, Dave, NREL
DeMeo, Ed, Renewable Energy Consulting
Detmer, Nick, Xcel
Ela, Erik, NREL
Ellis, Abe, Sandia
Fink, Sari, Exeter Associates
Flood, Ron, Arizona Public Service
Galen, Mark, Sandia
George, Ray, NREL
Gevorgian, Vahan, NREL
Jordan, Gary, GE
Lehr, Ron, AWEA
Lew, Debbie, NREL
Liberatore, Joe, WAPA
Miller, Curtis, Tri-State
Miller, Nick, GE
Milligan, Michael, NREL
Mooney, Dave, NREL
Piwko, Dick, GE
Porter, Kevin, Exeter Associates
Smith, Charlie, UWIG
Trent, Gary, TEP
Turchi, Craig, NREL
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